Impact of Carbon Prices on Wholesale Electricity Prices and Carbon Pass-Through Rates in the Australian National Electricity Market

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ABSTRACT

This paper investigates the effect of a carbon price on wholesale electricity prices and carbon-pass-through rates in the states comprising the Australian National Electricity Market (NEM). The methodology utilize an agent-based model, which contains many features salient to the NEM including intra-state and inter-state transmission branches, regional location of generators and load centres and accommodation of unit commitment features. The model uses a Direct Current Optimal Power Flow (DC OPF) algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The results include sensitivity analysis of carbon prices on wholesale prices and carbon pass-through rates for different states within the NEM.

Keywords: Carbon pass-through, Carbon price, Electricity prices, Agent-based model, DC OPF Algorithm, Australian National Electricity Market

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1. INTRODUCTION

Policies to abate carbon emissions have a range of economic impacts. Of central concern to governments has been the impact of such policies on the price of electricity. Fast rising electricity prices are politically damaging because they tend to affect low income groups disproportionately but rising electricity price also provides an incentive to reduce carbon emissions. Australia is an interesting case study in this regard, having introduced a relatively high \$23/tCO_2 carbon price in 2012. Prior to the introduction of this policy, compensation was provided to low- and middle-income groups to cover the anticipated transmission in price rises from wholesale to retail prices. But what exactly is the effect of a carbon price on wholesale electricity prices? This paper provides an answer to this question.

Understanding of and estimation of the carbon pass-through rate is essential to estimating the interaction between the carbon price and electricity prices and assessing the need, scope and role of industry assistance, including partial or complete allocation of free permits (e.g. 'grandfathering') (Reinaud 2007, Chen et al. 2008, Chernyavs'ka and Gulli 2008 , Freebairn 2008, Sijm et al. 2008, Simshauser 2008, Menezes et al. 2009, Simshauser and Doan 2009, Kim et al. 2010, Nelson et al. 2010, Sijm et al. 2012).

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This article examines carbon pass-through in Australia but this issue is of interest in many other countries, as many countries or states have or are planning to adopt carbon pricing. The Kyoto Protocol allows flexibility over mechanisms used by signatory countries to meet their emission targets. For instance, emission trading allows countries that exceed emission reduction targets to sell excess greenhouse gas permits to deficit countries, which links Emission Trading Schemes (ETSs) into an international market (Parliament of Australia 2013). Currently, there are several ETSs operating including the European Union (comprising 31 countries), Switzerland, New Zealand, Australia, Japan and Kazakhstan. Significant state based schemes include: USA Regional Greenhouse Gas Initiative (nine eastern states including New York and Massachusetts); Western Climate Initiative (five USA and Canadian states including California, Quebec and British Columbia); Japan (Metropolitan scheme in Tokyo and provincial scheme in Saitama Prefecture); and Canada (Alberta). Proposed schemes include: China (seven provinces and cities including Beijing and Shanghai); Republic of Korea, Belarus, Brazil, India, and Mexico (Sterk and Mersmann 2011, Climate Commission 2013, DIICCSRTE 2013, Evans et al. 2013, Parliament of Australia 2013).

We use an agent-based model of the NEM called the Australian National Electricity Market (ANEM) model to estimate the carbon pass-through rate, so evaluating the relationship between carbon prices and wholesale electricity prices. ANEM's methodology assumes an Independent System Operator (ISO) and uses Locational Marginal Pricing (LMP) to price energy by the location of its injection into, or withdrawal from, the transmission grid. ANEM is based on the American *Agent-Based Modelling of Electricity Systems* (AMES) model (Sun and Tesfatsion 2007a, 2007b). The ANEM model fully reflects the differences between the institutional structures of the Australian and USA wholesale electricity markets.[1]

We consider that the fuel-mix of the market will be of greater importance in ultimately determining carbon pass-through rates while acknowledging wholesale market structure could affect pass-through estimates, such as the transparency and bidding behaviour in day-ahead and balancing markets of a net pool market as in the USA. However, the gross pool market structure of the NEM provides advantage in estimating carbon pass-through rates because this market structure most closely matches the framework underpinning discussion of carbon pass-through in the broader literature.

The wholesale market of the NEM is a real time, 'energy only' market and a separate market exists for ancillary services (AEMO 2010). The ANEM model uses a DC OPF algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices. The ANEM model accommodates: intra-state and inter-state power flows; regional location of generators and load centres; demand bid information; accommodation of unit commitment features including variable generation costs, thermal limits, ramping constraints, start-up costs and minimum stable operating levels.

The next section examines carbon pass-through, the impact of carbon prices on wholesale electricity prices and claims made for industry assistance. Section 3 provides an outline of the ANEM model. Section 4 discusses implementation issues of the ANEM model. Sections 5 and 6, respectively, analyse the sensitivity of the wholesale price and carbon pass-through rate to carbon price. Section 7 discusses policy implications and Section 8 offers conclusions.

2. CONCEPT OF CARBON PASS-THROUGH

Carbon pass-through can be defined as the incidence of a fixed carbon price or tradable carbon permit and refers to the proportion of carbon price (expressed in $\$/tC0_2$) that is passed into

1. See Wild et al. (2012a), Section 1, for further details.

wholesale electricity spot prices (expressed in \$/MWh) (Nelson et al. 2010). The carbon pass-through rate is influenced by:

- Emissions intensity of the existing capital stock (Simshauser and Doan 2009, Kim et al. 2010, Nelson et al. 2010).
- Demand and Supply elasticities (Chen et al. 2008, Freebairn 2008, Menezes et al. 2009, Nelson et al. 2010, Sijm et al. 2012).
- Economics of existing substitutes allowing a switch from high to low carbon emission forms of generation (Simshauser and Doan 2009, Nelson et al. 2010).
- Availability of offsets or international credits (Nelson et al. 2010).
- Market competition, e.g. whether the market is competitive or characterised by oligopolistic or monopolistic structures (Chernyavs'ka and Gulli 2008, Nelson et al. 2010, Sijm et al. 2012).

Most carbon pass-through rate calculations make simplifying assumptions such as perfect competition and ignore transmission branch congestion and the spatial location of generators and demand centres within the transmission grid. Such calculations fail to consider market power and constraints other than generator capacity limits and least cost production. Least cost production involves dispatching the generator with lowest marginal cost first, followed by the generator with the next lowest marginal cost, and so on, (Sijm et al. 2006, Chen et al. 2008, Sijm et al. 2012). However, 'out of order' dispatch can arise under the following circumstances: when market power is exercised; account is taken of transmission and unit commitment features; the level of the carbon price changes the merit order and marginal generator; or the carbon price produces a demand response (Sijm et al. 2006, Chen et al. 2008).

Carbon price investigations in Australia fall within two broad categories: economy-wide and specific electricity industry studies. Economy-wide studies typically utilise Competitive General Equilibrium (CGE) modelling where full carbon pass-through is assumed (Allen Consulting 2006, Garnaut (2008, 2011a), Prime Ministerial Taskforce 2008, Department of Treasury 2011). Specific electricity industry studies usually model the wholesale electricity market using linear programming (MMA 2006, ROAM (2008, 2011), SKM-MMA 2011, ACIL Tasman 2012).

Many of these studies investigate carbon pass-through indirectly where wholesale electricity price are presented relative to a '*Business-As-Usual*' (BAU) benchmark without explicitly calculating the carbon pass-through rate (MMA 2006, NETT 2006, ROAM 2008, Garnaut 2011b). Later reports have been more likely to explicitly calculate the carbon pass-through rate, which reflects a growing concern over wholesale electricity price increases induced by a carbon price (Department of Treasury 2011, ACIL Tasman 2012).

Nelson et al. (2010) in a survey of Australian carbon pass-through rates find that state emission factors measured in ($tC0_2$/MWh), including the contribution of wind generation, produced a variable set of outcomes with Victoria (VIC) having the largest emissions intensity factor of 1.23 while Tasmania (TAS) had the lowest of 0.32. The emissions intensity factors for Queensland (QLD) and New South Wales (NSW) were 0.89 and 0.90 respectively while for South Australia (SA) it was 0.72, which reflects SA's higher concentration of wind generation. The NEM wide weighted average emissions intensity factor was 0.94.

Nelson et al. (2010) also demonstrate that Australian estimates of carbon pass-through varied significantly from 17% to 128% with a mean of 93.4% for stable generator bidding strategies. When capital stock 'fixity' is assumed, higher range values are found (Freebairn 2008). Department of Treasury (2011, p. 126) cite SKM-MMA (2011) and ROAM (2011) who estimate an aggregate carbon pass-through rate of 0.85. ACIL Tasman (2012, p. 27) estimate State carbon pass-through rates of: 0.83 (QLD), 0.91 (NSW), 0.68 (VIC), 0.63 (SA) and 0.48 (TAS). VIC's low pass-through rate results from competition with SA's low emission intensive gas and wind generation and with NSW's and TAS's hydro generation (ACIL Tasman 2012, p. 47).

Investigations of the EU ETS indicate that carbon pass-through rates are broadly correlated with average emission intensity levels. Reinaud (2007), Sijm et al. (2008), Kim et al. (2010) and Nelson et al. (2010) provide an overview of methods and carbon pass-through estimates.

In principle, two types of carbon pass-through rates have been identified in the literature: add-on and work-on. The 'add-on' pass-through rates are the carbon intensity rates of generators (Sijm et al. 2006). In comparison, the 'work-on' pass-through rates indicate how much of the carbon price is passed onto wholesale electricity prices. This work-on rate is dependent on each generator's carbon intensity or add-on rate, the merit order of dispatch, transmission constraints, unit commitment features, location of demand centres and generators and fuel-mix of generators located in different regions or nodes.

Significant levels of carbon pass-through indicate that consumers are bearing a large proportion of the carbon price/tax while a low rate indicates that producers are bearing a high proportion of the incidence of the carbon price/tax (Nelson et al. 2010). A high carbon pass-through rate also mitigates claims of generators for compensation as they pass these increased costs onto consumers in the form of higher wholesale electricity prices (Freebairn 2008).

Assuming competitive least cost dispatch, carbon pass-through rates can be compared with the emissions intensity factor of individual generators. This gives an indication of whether the wholesale electricity price increases confronting generators will be sufficient to cover their incremental carbon cost liabilities. If the carbon pass-through rate is less than a generator's emissions intensity factor, the generator will face a loss of market share and asset value relative to BAU. Their profitability will be eroded because growth in revenue attributable to increases in wholesale electricity prices will be less than carbon cost increases (Sijm et al. 2006, Freebairn 2008, Simshauser 2008, Simshauser and Doan 2009, Lambie 2010, Nelson et al. 2010). This reasoning has underpinned debate about the need, role and potential scope of grandfathering. However, Garnaut (2008) argued against this position because there is no history or precedent for compensating private sector owners of capital for loss of asset value associated with any other public or regulatory policy. Furthermore, the use of a carbon price policy instrument cannot be viewed as unanticipated by investors because concern over climate change has been around since the 1970's and use of carbon pricing mechanisms since the early 1990's (Menezes et al. 2009).

3. PRINCIPAL FEATURES OF THE ANEM MODEL

In this section, we provide an outline of the core features of the ANEM model which are:

1. The wholesale power market includes an ISO and energy traders that include demand side agents called Load-Serving Entities (LSE's) and generators distributed across the nodes of the transmission grid.
2. The transmission grid is an alternating current (AC) grid modelled as a balanced three-phase network.
3. The ANEM wholesale power market operates using increments of one hour.
4. The ANEM model ISO undertakes daily operation of the transmission grid within a single settlement system, which consists of a real time market settled using LMP.

5. For each hour of the day, the ANEM model's ISO determines power commitments and LMP's for the spot market based on generators' supply offers and LSE's demand bids which are used to settle financially binding contracts.
6. Transmission grid congestion in the spot market is managed via the inclusion of congestion components in the LMP.

The transmission grid contains 72 branches and 53 nodes (see Figures 1 to 5 in Wild et al. 2012a) covering QLD, NSW, VIC, SA and TAS where the States are linked by the following interconnectors: QNI and Directlink linking QLD and NSW; Tumut-Murray linking NSW and VIC; Heywood and MurrayLink linking VIC and SA; and Basslink linking VIC and TAS.

The major power flow pathways in the model reflect the major transmission pathways associated with 275, 330, 500, 275 and 220 KV transmission branches in QLD, NSW, VIC, SA and TAS, respectively. Key transmission data required for the transmission grid relate to an assumed base voltage value in kilovolts (kV), base apparent power in three-phase megavoltamperes (MVA), branch connection and direction of flow information, maximum thermal rating of each transmission branch in megawatts (MW) and transmission branch reactance in ohms (Sun and Tesfatsion 2007a, Section 2.2). Base apparent power is set to 100 MVA, an internationally recognized value. Thermal ratings of transmission lines and reactance values were supplied by the QLD, NSW and TAS transmission companies Powerlink, Transgrid, and Transend. For VIC and SA, the authors used values based on the average values associated with comparable branches in the three above states.

A LSE is an electric utility that has an obligation to provide electrical power to end-use consumers (residential, commercial or industrial). The LSE agents purchase bulk power in the wholesale power market each day in order to service customer demand (load) in a downstream retail market. We assume that retail demands exhibit negligible price sensitivity reducing to daily supplied load profiles (Sun and Tesfatsion 2007b).

Hourly regional load data for QLD and NSW was derived using regional load traces supplied by Powerlink and Transgrid. This data was then re-based to the state demand totals published by AEMO for the 'QLD1' and 'NSW1' markets (AEMO 2013). For the other three states, regional shares were determined from terminal station load forecasts contained in the annual planning reports published by the transmission companies Transend (TAS), Vencorp (VIC) and ElectraNet (SA). These regional load shares were then interpolated to a monthly time series using a cubic spline technique and then multiplied by the 'TAS1', 'VIC1' and 'SA1' state demand time series published in AEMO (2013) to derive regional load profiles for TAS, VIC and SA.

The "demand" published in AEMO (2013) is termed 'scheduled demand', which is the output of scheduled and semi-scheduled generation, transmission losses and large independent loads directly connected to the transmission grid. This is a net demand concept calculated from gross demand, after contributions from small scale solar PV and wind and large scale non-scheduled generation (including wind, hydro and bagasse generation) has been netted off to produce the net demand concept (AEMO 2012b).

Generators are assumed to produce and sell electrical power in bulk at the wholesale level. Each generator agent is configured with a production technology with assumed attributes relating to feasible production interval, total variable and marginal cost functions and fixed costs. Depending upon plant type, start-up costs might also be incurred. Each generator also faces MW ramping constraints that determine the extent to which real power production levels can be increased or decreased within the hourly dispatch horizon. Production levels determined from the ramp up and ramp down constraints must fall within the minimum and maximum thermal MW capacity limits of each generator.

The MW production and ramping constraints are defined in terms of 'energy sent out'—i.e. energy available to service demand. In contrast, variable costs and carbon emissions are calculated from the 'energy generated' production concept which is defined to include energy sent out plus a typically small amount of additional energy that is produced internally as part of the power production process. Variable costs of each generator are modelled as a quadratic function of hourly real energy produced by each generator (Sun and Tesfatsion 2007b). The variable cost concept employed incorporates fuel, variable operation and maintenance (VO&M) costs and carbon cost components. Fuel, VO&M and carbon emissions/cost parameterisation was determined using data published in ACIL Tasman (2009) for thermal plant and from information sourced from hydro generation companies for hydro generation plant.[2]

Optimal dispatch, wholesale prices and power flows on transmission branches are determined in the ANEM model by a DC OPF algorithm. The DC OPF algorithm utilised is that developed in Tesfatsion and Sun (2007a) and involves representing the standard DC OPF problem as an augmented strictly convex quadratic programming (SCQP) problem, involving the minimization of a positive definite quadratic form subject to linear equality and inequality constraints. The solution values are the real power injections and branch flows associated with the energy production levels for each generator and voltage angles for each node.

Formally, the DC OPF algorithm employed in the model is:

- Minimize Generator-reported total variable cost and nodal angle differences
  $$\sum_{i=1}^{I} [A_i P_{G_i} + B_i P_{G_i}^2] + \pi \left[\sum_{l_m \in BR} \delta_m^2 + \sum_{km \in BR, k \geq 2} [\delta_k - \delta_m]^2 \right],$$
  with respect to real-power production levels and voltage angles
  P_{G_i}, $i = 1,\ldots,I$; δ_k, $k = 2,\ldots,K$, subject to
- Real power balance (equality) constraint for each node $k = 1,\ldots,K$ (with $\delta_1 \equiv 0$):
  $0 = PLoad_k - PGen_k + PNetInject_k$,
  where
  - $PLoad_k = \sum_{j \in J_k} P_{L_j}$ (e.g. aggregate power take-off at node k),
  - $PGen_k = \sum_{i \in I_k} P_{G_i}$ (e.g. aggregate power injection at node k),
  - $PNetInject_k = \sum_{km \text{ or } mk \in BR} F_{km}$,
- $F_{km} = B_{km}[\delta_k - \delta_m]$ [e.g. real power flows on branches connecting nodes 'k' and 'm' (Sun and Tesfatsion 2007a, Section 3.1)].
- Real power thermal (inequality) constraints for each branch $km \in BR$ $k = 1,\ldots,K$ (with $\delta_1 \equiv 0$):
  $F_{km} \geq -F_{km}^{UR}$, (lower bound constraint: reverse direction MW branch flow limit)
  $F_{km} \leq F_{km}^{UN}$, (upper bound constraint: normal direction MW branch flow limit).
- Real-power production (inequality) constraints for each Generator $i = 1,\ldots,I$:
  $P_{G_i} \geq P_{G_i}^{LR}$, (lower bound constraint: lower hourly MW thermal ramping limit)
  $P_{G_i} \leq P_{G_i}^{UR}$ (upper bound constraint: upper hourly MW thermal ramping limit),

2. A derivation of the various cost components is outlined in Appendix A of Wild et al. (2012a).

where

$P_{G_i}^{LR} \geq P_{G_i}^{L}$, (lower hourly thermal ramping limit $\geq$ lower thermal MW capacity limit)

and

$P_{G_i}^{UR} \leq P_{G_i}^{U}$ (upper hourly thermal ramping limit $\leq$ upper thermal MW capacity limit).

'U' = upper limit and 'L' = lower limit, A_i and B_i are linear and quadratic cost coefficients of the variable cost function.P_{G_i} is real (MW) power production level of generator 'i'. δ_k and δ_m are the voltage angles at nodes 'k' and 'm' (measured in radians). Parameter π is a positive soft penalty weight on the sum of squared voltage angle differences. Variables F_{km}^{UN} and F_{km}^{UR} are MW thermal limits associated with real power flows in the 'normal' and 'reverse' direction on each connected transmission branch $km \in BR$.

The linear equality constraint refers to a nodal balance condition which requires that, at each node, power take-off (by LSE's located at that node) equals power injection (by generators located at that node) and power transfers from other nodes on 'connected' transmission branches. On a node by node basis, the shadow price associated with this constraint gives the LMP associated with that node, i.e. regional wholesale electricity spot price. The linear inequality constraints ensure that real power transfers on transmission branches remain within thermal limits and the real power produced by each generator remains within lower and upper thermal limits while also meeting hourly ramping production limits.

It should be recognised that the ANEM model differs in significant ways from many of the wholesale electricity market models used to investigate the impact of carbon pricing on the Australian electricity industry. First, the nodal structure of the ANEM model is more disaggregated than the structure underpinning many of the other wholesale market models. Depending upon the treatment of Snowy Mountains Region in the NEM, the grid structures associated with wholesale market models used previously often involve five or six nodes (corresponding to each state region in the NEM) and six or seven inter-state interconnectors—see MMA (2006)[3], ROAM (2008, Appendix A, p. II), SKM-MMA (2011, p. 62) and ACIL Tasman (2012, Section B.2). In contrast, the ANEM model contains 53 nodes and 72 transmission branches, including six inter-state interconnectors and 66 intra-state transmission branches—see Wild et al (2012a), Figures 1–5. The ANEM model is also more disaggregated than the transmission grid structure adopted by AEMO for the National Transmission Network Development Planning (NTNDP) Process, see AEMO (2012a).

Second, the solution algorithm used in the ANEM model is very different conceptually from the linear programming algorithms used in many of the other wholesale market models. In the ANEM model, quadratic programming is employed to minimise both nodal angle differences and generator variable costs subject to network limits on transmission branches and generation. Optimal power flows on transmission branches are determined from optimised nodal angle differences. Optimised nodal angle differences depend on transmission branch adjacency and bus admittance properties determined from the transmission grid's structure and branch reactance data (Sun and Tesfatsion 2007a, Section 4). Accounting for power flows in the equality constraints of

3. The model used in MMA (2006) further disaggregated the Queensland state region into four sub-regions MMA (2006, p. 50, 63).

the DC OPF algorithm allows the incorporation of congestion components in regional wholesale spot prices. These congestion components can produce divergence in regional spot prices associated with congestion on intra-state transmission branches, thereby producing variation in regional and state averaged carbon pass-through rates.

In contrast, the linear programming algorithms do not explicitly optimise power flows as part of the optimisation process, directly capture the impact of branch congestion on spot prices or account for any impact associated with congestion on intra-state transmission branches. Moreover, intra-state regional spot prices are not typically defined in these models.

4. PRACTICAL IMPLEMENTATION CONSIDERATIONS

The solution algorithm employed involves applying the 'competitive equilibrium' solution. This means that all generators submit their true marginal cost coefficients and no strategic bidding is allowed, thus permitting assessment of the true cost of generation and dispatch. We also assume that all thermal generators are available to supply power during the whole period under investigation. This assumption avoids the effect that planned or unscheduled outages of thermal generators would have on increasing costs and prices by constraining the least cost supply response available by all generation to meet demand. Thus, our objective is to investigate, in an *ideal* setting, how the true cost of power supply changes for the various carbon prices compared to a BAU scenario involving no carbon price.

The implementation details relating to unit commitment features and dispatch of thermal and hydro plant are the same as outlined in (Wild et al. 2012a, Section 3). Recall that the contribution of non-scheduled wind generation has been included by being netted off from demand used in the modelling while semi-scheduled wind generation has been excluded.[4] While all thermal generators were assumed available to supply power, the dispatch of thermal plant was optimised around assumed availability patterns for hydro generation units where water supply is unconstrained. If water supply and hydro unit availability were constraining factors, this would increase costs and prices by constraining the least cost supply response available of all generation to meet demand. This follows because the supply offers of hydro plant would be significantly higher than the case where water supply did not constrain hydro generation availability.

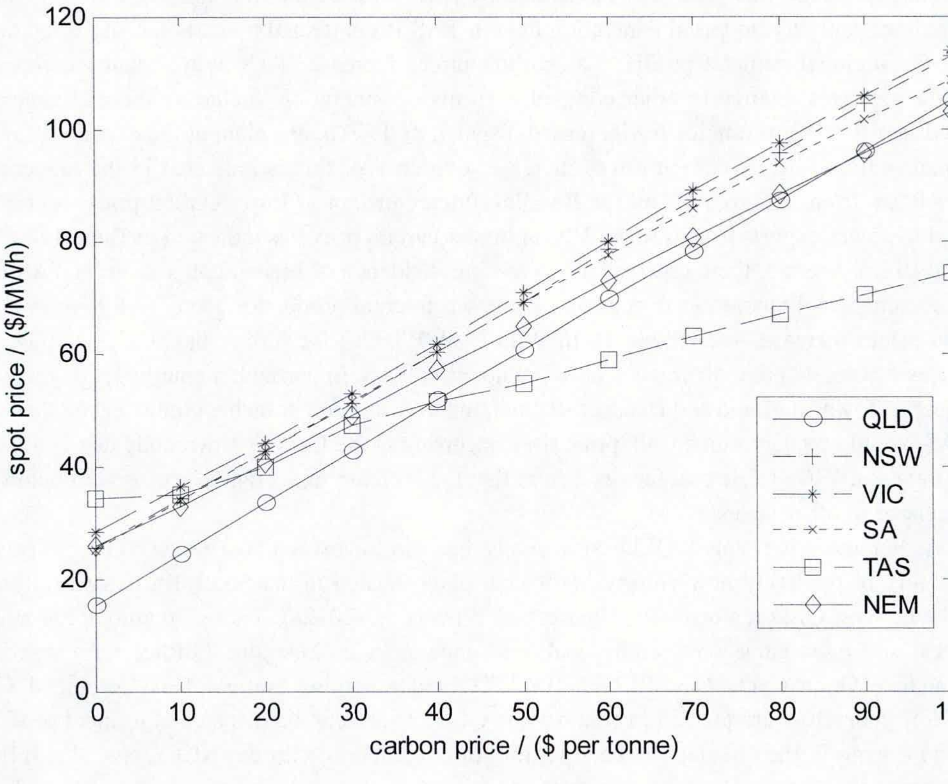
Pump storage hydro unit supply offers were based upon short run marginal costs to ensure that dispatch occurs in a synchronised manner with pump actions. For all remaining hydro plant, hydro generator supply offers were based on long run marginal costs. This approach reflected the assumption that hydro plant supply offers on the mainland was assumed to shadow peak load gas plant. Annual capacity factors obtained were consistent with the provision of peak-load production duties by mainland hydro plant (Wild et al. 2012a, Section 4.3). Supply offers of TAS hydro generation plant were also based on long run marginal costs. However, account was taken of the ability to provide baseload, intermediate or peak production duties when determining the long run marginal costs of TAS hydro plant. Annual capacity factors for TAS hydro generation were consistent with this approach. See (Wild et al. 2012a, Section 4.3) for further details.

5. WHOLESALE ELECTRICITY PRICE IMPACTS

This section examines the effect of a carbon price on wholesale electricity prices. Motivating this examination is Australia's electricity generation sector's high level of emissions by

4. Semi-scheduled wind generation only emerged in April 2009 and over the period 2007–2009 was therefore an insignificant component of the available generation fleet.

Figure 1: Three-year Averaged Yearly Spot Prices By State



international standards, which account for around 35% of all $C0_2$ emissions in Australia (Simshauser 2008, Simshauser and Doan 2009).

Figure 1 presents the average wholesale price for the years 2007 to 2009, for the NEM's five states and whole of NEM for carbon prices ranging from $10/t$C0_2$ to $100/t$C0_2$.

The average prices reflect both a spatial and temporal dimension. For each hourly dispatch interval in a given year, an average state price level was calculated by averaging across all relevant nodal prices within each state. The average annual price level for each state was then calculated by averaging across the number of hours in each respective year. Then the average annual price for the NEM was calculated by averaging across the five state average annual prices obtained for each of the three years being investigated. The three-year average annual results outlined in Figure 1 were then obtained by averaging across the yearly average annual price results obtained for years 2007, 2008 and 2009.

Figure 1 shows that the most notable result is that for TAS. It experiences higher average prices for carbon prices up to $10/t$CO_2$. This can be attributed to supply offers of TAS hydro plant being based on long run marginal costs. The resultant marginal cost is higher than those for thermal plant on the mainland. At higher carbon prices, electricity price rises more slowly than in other states. This is related to the possibility of trade with the mainland, via the Basslink Interconnector, which gives TAS exposure to cost structures and prices prevailing in VIC.[5] As carbon prices

5. This observation is reinforced by very low levels of congestion on Basslink, which only begins to emerge for carbon prices of $90/t$C0_2$ and $100/t$C0_2$—see Table 18 of Wild et al. (2012a) for further details.

increase, this promotes the increased dispatch of gas plant located at the George Town node, in particular. However, this growth is moderated by two factors. First, the variable cost structure of the predominantly hydro based generation fleet in TAS is unaffected by carbon costs. Specifically, given the regional demand profiles,[6] as carbon prices increase, TAS hydro plant's competitive position improves relative to other competing forms of generation, including thermal generation located in VIC. This promotes the increased dispatch of TAS hydro plant at the expense of output originating from VIC as carbon prices increase. Evidence of this is indicated in the reduction in power flows from VIC to TAS on the Basslink Interconnector at lower carbon prices and switch around to power exports from TAS to VIC at higher carbon prices as indicated in Table 17 of Wild et al. (2012a). Second, there emerges an increasing incidence of branch congestion on TAS intra-state transmission branches in response to increased internal production from TAS hydro plant as carbon prices increase,—see Table 16 in Wild et al. (2012a) for further details. This congestion produces wholesale price divergence between nodes in TAS. In particular, emerging congestion on the George Town-Sheffield and Hadspen-Palmerston transmission branches would ensure that much of TAS would be quarantined from price rises occurring at the George Town node that is linked to price trends in VIC. These two factors ensure that the increase in average prices is well below that experienced in other states.

For the other states, QLD consistently has the lowest average prices. This reflects the availability of relatively new vintage black coal plant located in the South Burnett (e.g. Tarong) and South West QLD regions—see Figure 1 of Wild et al. (2012a). These are among the newest, cheapest and most emission friendly coal-fired generators in Australia. Furthermore, significant intermediate Open Cycle Gas Turbine (OCGT) [and emerging Natural Gas Combined Cycle (NGCC)] generators are located in South West QLD. These can be dispatched to meet peak load demand arising in the Greater Brisbane region, in conjunction with the NGCC Swanbank E and Wivenhoe pump-storage hydro power stations whose ramping capabilities can match peak-load demand but at significantly lower costs than conventional OCGT peak-load gas generation.

NSW follows a similar pattern to QLD excepting, on average, the NSW black coal fleet is of older vintage, marginally more costly and has slightly higher carbon-emission intensity rates. Similarly, key NGCC and pump-storage hydro plant is also located in major population centres: Sydney and Wollongong regions[7]. This plant is well placed to ramp up to meet peak demand in these major population centres. However, the intra-state branch congestion in northern NSW and the Hunter region promotes price divergence between NSW and QLD as displayed in Figure 1—see Tables 16 and 18 in Wild et al. (2012a).

In SA, there is NGCC and gas thermal plant located in the Greater Adelaide region that can meet peak load conditions in the region.[8] This plant has the capacity to both set prices during peak demand periods and partially replace black coal generation located in the Upper North region of SA, as the carbon price increases. It has lower fuel and carbon costs than more conventional OCGT peaking gas plant and a variable cost structure that declines in relative terms to SA and VIC coal plant as the carbon price increases. Moreover, there is emerging evidence of branch congestion

6. It should be noted that by assuming that retail electricity demands exhibit negligible price sensitivity thereby reducing wholesale demand to daily supplied load profiles, we are excluding the possible impacts of a demand response to rising prices produced by the introduction of a carbon price signal. Thus, we are restricting analysis to consideration of the supply side response.

7. See Figure 2 of Wild et al. (2012a) for details.

8. See Figure 4 of Wild et al. (2012a) for details.

on the Murraylink Interconnector for medium and high carbon prices which can drive price divergence between VIC and SA prices as seen in Figure 1—see Table 18 in Wild et al. (2012a).

VIC consistently has the highest average wholesale prices for the three-year period and across all carbon prices considered. It has a traditional generation structure with brown coal generation used for base load and peak load met by OCGT peak gas or hydro plant. The brown coal generation, in the absence of a carbon price, is the cheapest in the country while the OCGT gas cost in VIC is more expensive than NGCC, Gas Thermal and intermediate OCGT plant located in other states. As such, with the incidence of peak load conditions in VIC and, to the extent that the marginal generator employs gas, it is likely to have a higher marginal cost structure than comparable units in other states.

However, NSW and VIC average prices seem to track closer together in Figure 1 at medium and higher carbon prices because there was very little branch congestion on intra-state and interstate transmission branches linking NSW and VIC—see Tables 16 and 18 of Wild et al. (2012a) for details.

Furthermore, at medium and higher carbon prices, gas generation in VIC becomes competitive to coal, partially displacing brown coal generation while hydro generation in VIC becomes more competitive relative to OCGT generation as a marginal (peaking) generator—see Wild et al. (2012a, Section 4.3) for further details. This means that prices in both NSW and VIC increasingly become determined by hydro at higher carbon prices, which becomes the marginal generator and whose variable costs are unaffected by rising carbon prices. So, the correspondence between spot prices in both NSW and VIC shown in Figure 1 results from both the lack of transmission congestion and similar marginal cost structures of the marginal generator in both States.

6. CARBON PASS-THROUGH RATES

The rate of carbon pass-through is calculated in a two-step process. First, the price difference between average annual wholesale price with and without a carbon price is calculated. This price difference is then divided by the carbon price (Wild and Bell 2013). A rate less than unity implies less than complete pass-through of the carbon price into average annual wholesale prices. In contrast a rate greater than unity implies more than complete pass-through, e.g. the carbon price has a 'magnified' effect on average annual prices.

We calculated carbon pass-through rates for carbon prices ranging from \$10/tCO_2 to \$100/tCO_2 incrementing by \$10/tCO_2 for the years 2007 to 2009. Table 1 shows the carbon pass-through rate averaged over the years 2007 to 2009. To see how sensitive the NEM average results are to the averaging operation adopted, we also derived a second set of NEM averages based on the state production shares listed in Table 1 of Nelson et al. (2010). The first set refers to simple arithmetic averages and are contained in column 7. The second set of weighted averages, termed 'NEM*,' are listed in the last column. This latter weighting scheme gives higher relative weight to QLD, NSW and VIC while reducing the relative weight attached to SA and TAS. These weighted average pass-through averages for the NEM are higher for all carbon prices.

Table 1 shows that there is less than complete pass-through as all rates are less than unity. Understandably, given its significant hydro generation, the carbon pass-through rate for TAS is much lower than for the other states. Note that our pass-through rates for TAS are a little bit lower than those cited in ACIL Tasman (2012, p. 27) of 0.48.[9]

9. The carbon pass-through rates cited in ACIL Tasman (2012) are also 'work-on' rates.

Table 1: 2007–2009 Average Carbon Pass-through Rates

Carbon Price	QLD	NSW	VIC	SA	TAS	NEM	NEM*
\$10/tC02	0.9177	0.8470	0.7994	0.8838	0.0869	0.7070	0.7981
\$20/tC02	0.9165	0.8419	0.7944	0.8669	0.2794	0.7399	0.7963
\$30/tC02	0.9150	0.8529	0.8160	0.8717	0.4338	0.7779	0.8086
\$40/tC02	0.9079	0.8591	0.8304	0.8728	0.4332	0.7807	0.8135
\$50/tC02	0.9032	0.8686	0.8483	0.8746	0.4116	0.7813	0.8209
\$60/tC02	0.9038	0.8748	0.8615	0.8722	0.4128	0.7850	0.8272
\$70/tC02	0.8996	0.8750	0.8639	0.8664	0.4114	0.7833	0.8267
\$80/tC02	0.8974	0.8747	0.8634	0.8581	0.4083	0.7804	0.8254
\$90/tC02	0.8967	0.8735	0.8608	0.8484	0.4045	0.7768	0.8235
\$100/tC02	0.8969	0.8706	0.8554	0.8344	0.4000	0.7715	0.8202

A more surprising finding is the relatively low levels of carbon pass-through experienced in VIC up to \$60/tCO_2 compared to QLD, NSW and SA. This is surprising given the higher state carbon emissions intensity factor identified in Nelson et al. (2010) when compared to equivalent rates for the other three states. However, their carbon pass-through concept is, in the terminology of Sijm et al. (2006), the 'add-on' or generation carbon intensity rates. The estimates presented here are 'work-on' rates using the terminology of Sijm et al. (2006). It should be noted that ACIL Tasman (2012, p. 27) also obtained relatively low pass-through rates for VIC relative to QLD and NSW—e.g. 0.83 for QLD, 0.91 for NSW and 0.68 for VIC.

The trends from our modelling in relation to NSW and VIC are noteworthy given the relatively large size of both markets and different 'add-on' rates associated with the generation structure of both states. Specifically, Table 2 shows that for carbon prices below \$80/t$C0_2$, the difference between average prices in VIC relative to BAU is lower when compared to NSW but also tends to approach the results of NSW as the carbon price level increases beyond \$50/t$C0_2$ before beginning to diverge somewhat for carbon prices greater than \$80/t$C0_2$. This finding reflects the fact that lower end carbon prices can be absorbed, to a large extent, by VIC brown coal generators because of the very low marginal cost involved. However, by the time that the carbon price exceeds \$50/tCO_2, there has occurred a significant transition with a reduction in brown coal generation and an increase in the dispatch of gas and hydro plant in VIC and the carbon pass-through becomes broadly comparable to NSW, as outlined in Wild et al. (2012a, Section 4.3).

Table 1 shows QLD has the highest level of carbon pass-through at all carbon prices. This occurs because, at all carbon prices, the difference in average prices in QLD relative to BAU is higher when compared to other states, as shown in Table 2. This reflects two broad factors. First, congestion on transmission branches in northern NSW and the Hunter region of NSW promotes price separation between QLD and NSW. Second, at higher carbon prices, both newer vintage coal and NGCC generation partially displaces old and medium vintage coal production whilst OCGT gas generation, instead of hydro generation, increasingly plays the role of marginal generator in determining prices in QLD—see Wild et al. (2012a, Section 4.3). Note that our results for QLD differ from those obtained by ACIL Tasman (2012) who obtained a carbon pass-through rate of 0.83. In their results, NSW was the state with the highest pass-through rate of 0.91. Difference in modelling assumptions between ANEM and ACIL Tasman (2012) can heuristically explain this

Table 2: 2007–2009 Average Price Difference ($/MWh) Relative to BAU

Carbon Price	QLD	NSW	VIC	SA	TAS
$10/tC02	9.18	8.69	8.35	8.95	0.69
$20/tC02	18.37	17.47	16.51	17.53	5.62
$30/tC02	27.51	26.19	25.40	26.52	13.40
$40/tC02	36.36	35.26	34.22	35.33	16.82
$50/tC02	45.18	44.12	43.47	44.24	19.10
$60/tC02	54.25	53.42	52.72	52.94	22.63
$70/tC02	62.90	62.13	61.48	61.23	26.07
$80/tC02	71.85	70.65	70.08	69.40	29.50
$90/tC02	80.81	79.37	78.61	77.36	32.83
$100/tC02	89.81	88.04	86.66	84.59	35.98

disparity such as differences in transmission grid structure, intra-state and inter-state power flows, levels of demand aggregation and supply offer behaviour.

Table 1 also shows that the carbon pass-through rate of SA is generally higher for small to moderate carbon prices but becomes lower, in comparison with NSW and VIC at higher carbon prices. This occurs because, at carbon prices greater than $\$60/tC0_2$, the difference in average wholesale prices in SA relative to BAU is lower than the price differential in VIC and NSW, as shown in Table 2. This reflects the substitution of gas for coal generation as higher carbon prices reduce production levels from the latter towards each plant's minimum stable operating level—see Wild et al. (2012a, Section 4.3). This, in turn, promotes the increased export of power from SA to VIC (especially for carbon prices of $\$40/tC0_2$ and higher)—see Table 17 of Wild et al. (2012a). Increased congestion on the Murraylink Interconnector as the carbon price increases also promotes price separation between VIC and SA—see Table 18 of Wild et al. (2012a) for details. This would be capable of producing divergence between carbon pass-through rates associated with VIC and SA. Note that our results for SA also differ substantially from those cited in ACIL Tasman (2012) who obtained a carbon pass-through rate of 0.63.

For QLD and SA, the level of carbon pass-through generally declines as the carbon price increases. This again reflects the substitution of gas fired generation at the margin for black coal generation. This fuel switching becomes more prominent as carbon prices increase (Wild et al. 2012a, Section 4.3).

Table 1 also shows NEM wide carbon pass-through rates for carbon prices between $\$20/tC0_2$ to $\$30/tC0_2$ of between 0.74 and 0.78 and 0.80 and 0.81 respectively, depending on whether the 'NEM' or 'NEM*' weighting schemes are applied. These results can be compared with the 0.85 'work-on' rate cited in Department of Treasury (2011, p. 126). Similarly, given the state carbon pass-through estimates reported in ACIL Tasman (2012, p. 27) of 0.83 (QLD), 0.91 (NSW), 0.68 (VIC), 0.63 (SA) and 0.48 (TAS), applying the 'NEM' and 'NEM*' weighting schemes to these numbers produces aggregate carbon pass-through rates of 0.71 and 0.79, respectively.

7. POLICY IMPLICATIONS

The following findings have policy implications.

There is divergence in carbon pass-through rates between 'work-on' and 'add-on' rates. Nodal price equalisation when transmission branch congestion is absent and nodal price divergence when transmission branch congestion is present drives differences between 'add-on' and 'work-on' carbon pass-through estimates.

Carbon pass-through estimates are dependent upon the nodal location and the fuel-mix of generation plant within the transmission grid; for example, compare Tasmania's carbon pass-through rates with those for the mainland states. Differences in rates also arise between the mainland States, reflecting differences in fuel-mix and vintage of generation plant, and with variation in the carbon price. Thus, the variability in carbon pass-through rates in relation to state location and carbon price raises questions about the efficacy of policy based on a single economy-wide carbon pass-through rate to determine retail electricity tariffs.

Retail commercial and industrial customers often use '*Over-The-Counter*' (OTC) contracts to set retail electricity prices. In the OTC market, there is a standard clause that links the forward price to some agreed strike price related to expected energy cost plus a carbon cost component. This latter provision equates to the carbon price times the average carbon intensity (ACI) rate which references the whole of NEM carbon intensity (e.g. carbon pass-through) rate. The ACI concept does not attempt to capture the implications of differences in carbon pass-through rates of the different states. This could produce windfall gains (by retailers) by inflating contract prices if a state's carbon pass-through rate is less than the ACI rate and losses by understating contract prices if the state's carbon pass-through rate is greater than the ACI rate—see Wild et al. (2012b, Section 7) for worked examples demonstrating this. This result implies that regional differences in carbon pass-through rates could be taken into account in the design of OTC hedge products, giving these products a spatial context. This would produce more efficient price signals by accounting for differential impacts associated with differences in the generation fuel-mix and age of plant, installed generation capacity constraints, transmission infrastructure servicing the regional demand and transmission constraints possibly arising at times of regional demand peaks. However, this improvement in efficiency would come at the expense of increased administrative complexity in both product detail and administrative costs in determining regional based carbon pass-through rates. Furthermore, while the focus of this article has been on a gross pool energy-only wholesale market structure, the principles could be readily extended to a net pool market structure based around a combined day-ahead and real time balancing market as well as longer horizon capacity market structures.

Divergence between 'work-on' and 'add-on' carbon pass-through rates also raises questions about partial compensation for adversely affected generation plant. In the current context, the measure of adversity would be directly related to the extent to which each generators 'add-on' carbon pass-through rate exceeds the relevant state 'work-on' carbon pass-through rate. The results indicate that coal generation plant in Victoria and, for higher carbon prices, coal plant in South Australia are absorbing carbon costs to a greater extent than black coal plant in New South Wales and Queensland. Moreover, black coal plant in New South Wales also absorbs carbon costs to a greater extent than is the case with black coal plant in Queensland.

8. CONCLUDING REMARKS

In this article, we have reported on a detailed investigation of the 'pass-through' impact of carbon pricing on the wholesale price of electricity. We have examined the case of Australia which in 2012 introduced a starter carbon price of \$23/tCO_2. A survey of the literature demonstrated that the concept of carbon pass-through is crucial to understanding and estimating the interaction between a carbon price and wholesale electricity prices. It was argued that to address this, a model of the national electricity market is required that contains many realistic features of what is a complex, networked system. Such features include intra-regional and inter-state trade, realistic transmission network pathways and the competitive dispatch of all generation with price determination based upon marginal cost and transmission branch congestion.

To capture these linkages, we used an agent-based model of the Australian National Electricity Market, incorporating a DC OPF algorithm to determine optimal dispatch of generation plant, power flows on transmission branches and wholesale prices.

There are a number of broad conclusions. First, TAS experienced higher average wholesale prices for zero or low carbon prices compared to other states while also experiencing much more modest growth in average wholesale electricity prices as the carbon price increases. This relates to how hydro generators in TAS were assumed to offer supply. For the mainland states, QLD consistently had the lowest average wholesale prices, followed by SA and then NSW. VIC consistently has the highest average wholesale prices.

For all states, we found that there was less than complete pass-through of carbon price into average wholesale prices. We found significant variability in carbon pass-through rates across states and at different carbon prices, raising fundamental questions about the efficacy of using one single aggregate measure of carbon pass-through, such as the Average Carbon Intensity (ACI) rate that has been proposed in the standard clause provision in OTC market transactions. Furthermore, divergence between 'work-on' and 'add-on' carbon pass-through rates raises questions over the possibility of partial compensation of adversely affected coal plant in VIC and SA, and to a less extent, in NSW.

With regard to the robustness of our results, modelling based on past behaviour can, of course, never fully capture real events in the future. However, the modelling methodology has enabled us to create realistic scenarios that we would expect to hold up well for a number of years. Early indications support this—our estimates of increases in state level and NEM level electricity price rises, computed before the introduction of carbon pricing in July 2012, are very close to the actual outcomes and superior to the Australian Commonwealth Treasury's estimate of the NEM electricity price rise (state estimates were not available). We would not expect our scenarios to be robust for carbon prices in excess of \$70/tCO_2 because, above that price, it is likely that renewables, nuclear, geothermal and/or carbon capture and storage will begin to play a more significant role in electricity generation. Furthermore, future trends in coal and especially gas prices will affect substitution of fuels and thermal generation production patterns which, with growth in renewables, is also likely to lead to new network investment over time that together can affect outcomes. But, right now, these outcomes and their relative contributions, perhaps decades ahead, reside in the domain of uncertainty and are, thus, not amenable to realistic scenario modelling.

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